NEPOOL RESTRUCTURING PROPOSAL

Presented to the NEPOOL Executive Committee

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I. Overview

This NEPOOL Restructuring Proposal provides the outline of a new structure for the New England Regional electricity market that will be made up of three main components: (1) an Independent System Operator ("ISO"); (2) an amended NEPOOL Agreement that includes Regional Transmission Committees and Market Committees; and (3) a contractual arrangement between NEPOOL and the ISO. (See Figure 1, p. 5, depicting the proposed restructured NEPOOL).

Under the Proposal, the ISO will be a truly independent entity with a separate legal existence as a non-profit corporation. It will have its own directors, officers and employees who will have no financial interest in any of the market participants or the NEPOOL market transactions.

The ISO will have a self-perpetuating board of directors who are not controlled by or associated with any of the NEPOOL Participants, or other entities directly or indirectly involved in the market .

To maintain its neutrality, the ISO will not be a market participant, except to the extent necessary to ensure system reliability. The ISO will have the authority to independently conduct system assessment and planning and to assess the competitiveness and efficiency of the NEPOOL market, thereby ensuring that potential market power problems are identified and effectively mitigated.

The primary mission of the ISO will be to act as a neutral implementer and monitor of the rules and market protocols in a manner that ensures non-discriminatory access to and reliable

operation of the regional electric system at least cost to the market participants and their customers.

The general roles and responsibilities of the ISO will be: (1) to direct the operation of the transmission system, to process applications for transmission service, and to conduct system planning and assessment; (2) to coordinate generation resources under a system of central dispatch; (3) to facilitate the market by administering a regional power exchange, including taking bids, calculating clearing prices and settling transactions; and (4) to keep confidential commercially sensitive information while disseminating that information that should be available to all market participants.

NEPOOL will remain a wholesale power pool and a voluntary association of eligible Participants under an Agreement regulated by the FERC. NEPOOL, with the ISO's assistance, will establish the rules to ensure reliable, efficient and non-discriminatory operation of the regional integrated electric system and a competitive and efficient electricity market . There will be one NEPOOL Agreement that will encompass both the transmission and the market aspects of the regional electric system. The NEPOOL Agreement will be developed and amended by NEPOOL Participants based on a principle of single group, multi-factor voting that reflects the business interests of the participants.

The business interests of NEPOOL Participants will be represented on six committees that will administer the NEPOOL Agreement. The Regional Transmission Operations Committee ("RTOC") will have responsibility for overseeing and amending the regional transmission tariff and will provide the rules governing operation of the transmission system. The RTOC will also have the responsibility for developing rules governing the pricing of

transmission services. The RTOC's rules will provide for comparable treatment of all entities. The transmission pricing provisions will be designed to assure efficiency and equity, while being consistent with public policy and FERC regulation. The Regional Transmission Planning Committee ("RTPC") will have responsibility for long range transmission planning.

The Market Operations Committee will provide the rules of operation for a system of central dispatch of generation, and will provide the rules governing services that support central dispatch. Participants will have a limited right to self-schedule their resources to the extent they do not jeopardize reliability. The system of dispatch we envision is essentially the same as the system outlined by the NEPOOL Review Committee in Appendix 3 of their *Phase One Report.* The Market Operations Committee will also provide the rules governing bidding, calculating market clearing prices, control of confidential market information and settling market transactions. The Market Reliability Planning Committee will have responsibility for generation resource adequacy studies and long range generation resource planning. These four committees will report up to a NEPOOL Executive Committee and a NEPOOL Management Committee, that will have essentially the same roles and responsibilities as those committees now have. NEPOOL, through these various committees, and in conjunction with the ISO, will provide the rules, consistent with NERC requirements and approved by the FERC, under which the ISO will operate the system.

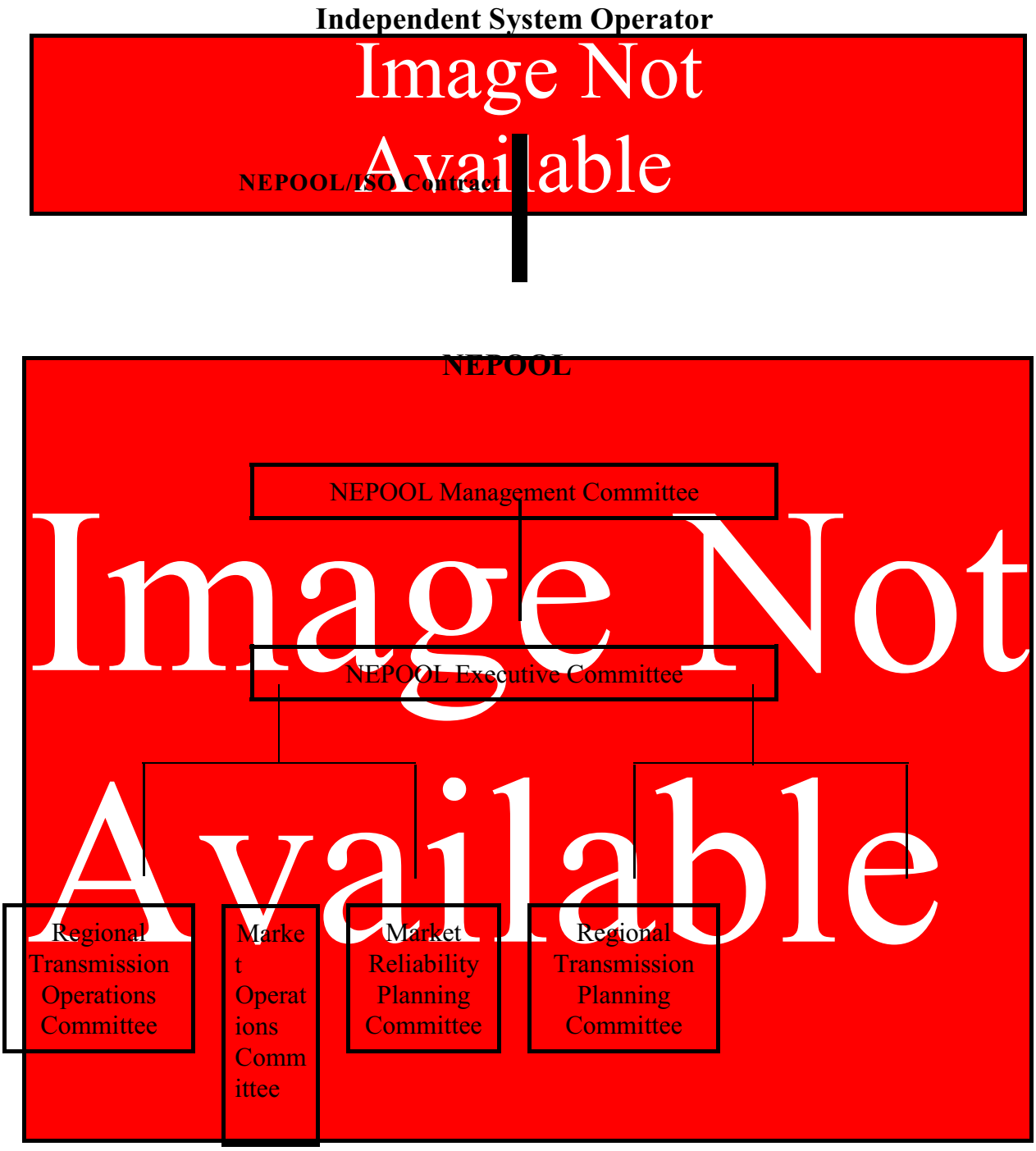
There will be a contract between NEPOOL and the ISO. The contract between NEPOOL and the ISO will contain at least the following general elements: (1) a definition section; (2) a description of the respective rights and obligations of the ISO and NEPOOL Participants ; (3) standards of conduct governing the ISO's interaction with market participants; (4) an ISO budget,

funding and payment provision; (5) an indemnification, liability and insurance provision; (6) a termination provision, including a notice provision; (7) a dispute resolution provision; and (8) a governing law provision.

II. Organization of Restructured NEPOOL

Due to the industry movement towards a competitive electric market, the organizational structure of NEPOOL needs to be modified to accommodate the numerous changes contemplated. Since its inception, NEPOOL has provided its Participants and the New England consumers with the economic and reliability benefits of a central dispatch of independently operated electric companies. While NEPOOL has been successful for the past twenty-five years, it now must undergo substantial change to facilitate competitive markets, ensure comparability and allow for retail choice, while maintaining the efficiencies, reliability and independence that NEPOOL has provided for the New England region in the past. To accomplish this goal, NEPOOL's organizational structure must be modified to accommodate the Independent System Operator, incorporate the changes to regional transmission operation and planning, and provide for continued governance over the modified market rules and settlement system proposed for the NEPOOL Agreement. Figure 1 illustrates the proposed new structure for NEPOOL and the Independent System Operator (ISO).

Figure 1 - Restructured NEPOOL



Our proposal contemplates two separate organizations: the ISO and NEPOOL. The ISO will operate the bulk power and transmission systems, administer a power exchange and implement the rules of the markets, and administer the regional transmission tariffs. These functions will be performed by the ISO in a completely independent, neutral and non-discriminatory manner. The Independent System Operator will be governed by a board of directors who are not associated with any of the market participants. The ISO will have authority to conduct independent system planning and assessment and to assess the competitiveness and efficiency of the market.

NEPOOL will continue to be a voluntary, self governing organization, regulated by the FERC. NEPOOL will define the rules for the various markets and for the operation of the transmission system. Therefore NEPOOL Participants, with the assistance of the ISO, will determine the operational and planning rules for the new market structure, the pricing and planning rules for the regional transmission grid, and the process for resolution of disputes when they arise.

Entities eligible to participate in NEPOOL will be those entities who are eligible under the NEPOOL Agreement's definition of "Entity", which has been expanded to be as inclusive as

practicable for a wholesale power pool. New England State Commissioners will have an ex-officio (non-voting) membership role in all committees.

Coordination between the ISO and NEPOOL will be achieved through a performance contract. The contract will govern the interaction and dispute process between the ISO and the market participants.

The following Sections describe the roles, representation and voting structures for the various committees and boards charged with oversight of the operations, planning and settlement of NEPOOL, the ISO and the contract between them.

II.A. NEPOOL Agreement Structure

II.A.1. NEPOOL Today

The NEPOOL Agreement is governed by its Participants through a committee structure. Four functional committees comprise the decision making bodies for the Agreement. The NEPOOL Management Committee (NMC) is the ultimate decision and rule making body for the Agreement and the final NEPOOL committee in which disputes can be heard. Each Participant in the Agreement has a representative on this committee. A Participant's voting weight on the NMC is allocated as a function of the Participant's peak load which serves as a proxy for their total business interest in NEPOOL. In an unbundled restructured environment, voting weight based on peak load responsibility is a concern because it is no longer representative of all Participants' business interests and corresponding responsibilities and obligations under the Agreement.

The NEPOOL Executive committee is the acting committee of the NMC. The NMC appoints 10 senior executives from the various Participants to represent the NMC views and

concerns in a smaller operating group. In selecting the NEC, the NMC considers geographic distribution, relative sizes of the Participants and the public and private sectors of the electric utility. As restructuring and unbundling occurs, the issues considered by the NMC in choosing the NEC representatives need to be expanded to include the new types of entities operating in the electric industry.

The NEPOOL Operations Committee is charged with developing and implementing the operating rules for the NEPOOL Agreement. Additionally, the NOC is charged with the administration of the NEPOOL settlement system. The NOC members are selected by set rules with each NEPOOL Participants over 3% of total NMC voting having an individual seat on the committee. Larger Participants with over 20% total NMC voting weights are given a second seat on this committee. Smaller Participants that fall under the 3% NMC voting weight are provided representation under two consolidated seats, one for public interest and one for small private interests.

The NEPOOL Policy Planning Committee is charged with setting long term policy objectives for NEPOOL. This committee has a very similar Participant structure as the NOC and identical concerns with respect to representation of the newer participants in the group structure.

II. A.2 Restructuring Proposal

II. A.2.a NEPOOL Management Committee

Role Of Committee - The NEPOOL Management Committee ("NMC") will continue to be the ultimate decision and rule making body that can implement changes to the NEPOOL Agreement. The NMC will also continue to be the final step within NEPOOL for dispute

resolution, which can be accommodated through direct negotiations at the committee level or through a formal dispute resolution process.

Committee Representation - Each Participant in NEPOOL will have at least one representative on the Management Committee to vote the Participant's business interest. . Transmission providers, if they have other affiliated interests, may appoint an additional representative to represent the entities regulated transmission interest. Participants who choose to have separate transmission and market representatives will vote in accordance to the agreed upon voting structure (as described below) and in accordance with the mandatory FERC Standards of Conduct.

Voting Shares - Each Participant in the NEPOOL Agreement will receive an apportioned voting weight with respect to their membership in the Agreement and their business interests within the region. No Participant will exceed 25% of the total NMC voting weight. Participants with total business interests greater than 25% of total NEPOOL voting, will be capped at 25% with the remaining portion of their vote (above 25%) allocated to the other NEPOOL Participants on a pro rata basis. The Passage of an action item will continue to need a supermajority of Participants. Passage of an action item will require 66% of the total NMC voting shares to vote affirmatively. Blockage of an action item will be achieved by not getting the affirmative votes needed or when 20%of the Participant's total NMC voting weight, from at least 3 non-affiliated entities (with the largest entity contributing no more than 18% of the 20%), vote negatively. Additionally, amendment of the NEPOOL Agreement will require signatures from 66% of the voting shares of the NMC. Amendments will be continue to be approved by gathering signatures. Blockage of an amendment may be achieved by not getting the affirmative signatures

needed or when 20% (of the NMC voting weight) of the Participants signing the amendment, from at least 2 non-affiliated entities (with the largest entity contributing no more than 18% of the 20%), provide negative signatures. This structure will ensure that a majority of Participants are in agreement on the issue, reducing the likelihood of formal dispute, but will not allow a single Participant or related entity to block an action or an Amendment to the Agreement. The 25% cap on NMC voting also ensures that no one entity has a large enough vote to dominate voting within NEPOOL. The following section details the voting weights for the NMC.

The percentage of the aggregate Voting Shares of all Participants to which a Participant is entitled in any month will be determined as follows:

$$V = .15833\left(\frac{P}{P^1}\right) + .15833\left(\frac{E}{E^1}\right) + .15833\left(\frac{C}{C^1}\right) + .15833\left(\frac{X}{X^1}\right) + .05\left(\frac{Y}{Y^1}\right) + .15833\left(\frac{M}{M^1}\right) + .15833\left(\frac{R}{R^1}\right)$$

in which

V = the Participant's Voting Share as a percentage of the aggregate Voting Shares of all Participants;

P = the average of the Participant's Monthly Peaks for the most recent twelve months, as of the beginning of the current month (this peak includes retail, wholesale all/partial requirements and contract demand peaks);

P^1 = the average of the aggregate noncoincidental Monthly Peaks for the most recent twelve months of all Participants, as of the beginning of the current month;

E = the average of the Participant's monthly Loads (energies) for the most recently completed twelve months (this energy served includes retail, wholesale all/partial requirements and contract demand energy served);

E^1 = the aggregate of the average monthly Loads (energies) of all the Participants for the most recently completed twelve months;

C = the average in megawatts for the most recently completed twelve months of the sum for each month of the Ownership Shares of the Participant, as determined without giving effect to any Unit Contract sales by the Participant.

C^1 = the average in megawatts for the most recently completed twelve months of the sum for each month of the Ownership Shares of all Participants, as determined without giving effect to any Unit Contract sales by the Participants;

X = the average for the most recently completed twelve months of the sum for each month of (i) a number of kilowatt-hours equal to the kilowatts of the Participant's Ownership Shares times the number of hours in the month (this MWh factor recognizes participant's owned units transactions to wholesale or retail marketers) plus (ii) a number of kilowatt-hours equal to the number of kilowatts purchased by the Participant during the month under Unit or System Contracts times, in the case of each contract, the number of hours the contract was in effect in the month (this MWh factor recognizes all of the participant's wholesale contract purchases and includes unit, system, external purchases, etc.). The sum of these factors represents the total transactions completed within NEPOOL and was deemed representative of business interest for transactions.

X^1 = the average for the most recently completed twelve months of the sum for each month of (i) a number of kilowatt-hours equal to the kilowatts of the Ownership Shares of all Participants times the number of hours in the month (this MWh factor recognizes all

of NEPOOL Participant's unit owners transactions to wholesale or retail marketers), plus (ii) a number of kilowatt-hours equal to the aggregate number of kilowatts purchased by all Participants during the month under Unit or System Contracts times, in the case of each contract, the number of hours the contract was in effect in the month (this MWh factor recognizes all of NEPOOL Participant's wholesale contract purchases and includes unit, system, external, etc purchases). This factor represents the total transactions completed within NEPOOL and was deemed representative of total business interest for transactions.

Y = 1; and

Y^1 = the number of NEPOOL Participants at the beginning of the month.

M = the Participant's PTF transmission facilities, measured in miles (with allocation for joint owned facilities based on ownership shares);

M^1 = the aggregate of all Participant's PTF transmission facilities, measured in miles (with allocation for joint owned facilities based on ownership shares);

R = the Participant's investment in PTF transmission facilities;

R^1 = the aggregate of all Participant's investment in PTF transmission facilities.

For purposes of the foregoing definitions, the Ownership Share of a Participant means and includes:

(i) the direct ownership interest which the Participant has as a sole or joint owner in the Capability of a generating unit which is subject to NEPOOL central dispatch in accordance with Section 12.2 (this definition reflects direct ownership of units);

(ii) the indirect ownership interest which the Participant has, as a shareholder in Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company, Vermont Yankee Nuclear Power Corporation or a similar corporation, or as a general or limited partner in Ocean State Power or a similar partnership, in the Capability of a generating unit which is subject to NEPOOL central dispatch in accordance with Section 12.2, provided the corporation or partnership is itself not a Participant (this definition handles specific ownership of the Yankees, OSP);

(iii) any other interest which the Participant has in the Capability of a generating unit which is subject to NEPOOL central dispatch in accordance with Section 12.2, under a lease or other contractual arrangement, provided the other party to the arrangement is itself not a Participant and the Management Committee determines, at the request of the affected Participant, that the Participant has benefits and rights, and assumes risks, under the arrangement with respect to the unit which are substantially equivalent to the benefits, rights and risks of an owner (this definition addresses the situation where a owner may enter into a contract with a financial institution for ownership and then leaseback of a plant); and

(iv) an interest which the Participant shall be deemed to have in the direct ownership interest, or the indirect ownership interest as a shareholder or general or limited partner, of a Related Person of the Participant in the Capability of a generating unit which is subject to NEPOOL central dispatch in accordance with Section 12.2, provided the Related Person is itself not a Participant (this definition addresses the situation where a Participant's related company has ownership of a

plant, but is not a NEPOOL Member, the ownership vote goes to the related Participant).

For purposes of this Restructuring Proposal, a "Related Person" of a Participant is either (i) a corporation, partnership or other business organization in which all of the stock or other equity interest is owned directly or indirectly by the Participant, or (ii) a corporation, partnership or other business organization which owns directly or indirectly all of the stock or other equity interest in the Participant, or (iii) a corporation, partnership or other business organization in which all of the stock or other interest is owned directly, or indirectly by a corporation, partnership or other business organization which also owns all of the stock or other equity interest in the participant.

Participants who choose to vote their transmission and market interests separately, will appoint two representatives to the NMC. Each representative will vote the market or transmission business interest of the company, respectively, as determined by the NMC voting formula.

The changes proposed in the NMC voting will replace the present basis for Management Committee voting, which is solely on the basis of load responsibilities. The new formula will provide votes to all Participants, including independent power producers and power marketers which may have no Load responsibilities. The new formula will allocate 5% of the votes on a per capita basis, and the balance on the basis of generation ownership, transactions, load and transmission ownership.

The basis for the lower weighting factor for transmission ownership versus the market is the assumption that the transmission cost of service is fully recovered under the regional

transmission tariff. Nonetheless, transmission providers will have to finance, install and maintain transmission facilities and therefore need adequate representation on the Management Committee. We believe that this proposed governance structure is more appropriate for our region than the three sector structure used in the SWRTA and WRTA regional transmission groups. Unlike our situation, these groups have no regional transmission tariff and no centralized planning to any extent. Therefore, it is not expected that these two RTG's will require governance and voting on pricing or planning issues. Although the three sector structure (transmission owners, TDU's, NUG's and Marketers) may be appropriate for an RTG having only administrative issues to govern, we believe it is not adequate to protect the business interests of NEPOOL Participants.

We have made our proposal for transmission governance more inclusive than the PJM model, which limits participation in governance of transmission issues to transmission owners.

II.A.2.a.1 Dispute Resolution

General:

Any Participant which is aggrieved by a vote of the Management Committee to approve or reject a proposed action under this Agreement may, as provided below and subject to the obligation of good faith, submit the matter for resolution hereunder if the vote:

(1) requires such Participant to make a payment or to take any action pursuant to this Agreement; or

(2) reduces the amount of any receipt or forbids, pursuant to this Agreement, the taking of any action by the Participant; or

(3) fails to afford it any right to which it is entitled under the provisions of this Agreement or imposes on it a burden to which it is not subject under the provisions of this Agreement; or

(4) results in the termination of the Participant's status as a Participant or imposes any penalty on the Participant; or

(5) results in an allocation of transmission or other facilities support obligations; or

(6) fails to grant in full the Participant's application for transmission service pursuant to the NEPOOL Open Access Transmission Tariff.

No legal or regulatory proceeding (except those reasonably necessary to toll statutes of limitations, claims for laches or other bars to later legal or regulatory action) shall be initiated by any Participant with respect to any such matter while proceedings are pending under this Section with respect to the matter.

Procedure:

(1) **Submission of a Dispute**: Any Participant seeking review of a vote of the Management Committee shall give written notice to the Secretary of the Management Committee within 10 business days of the vote, and shall mail or telecopy a copy of its notice to each member of the Management Committee.

(2) **Suspension of Action**: The vote to be reviewed shall be suspended pending resolution of any arbitration proceeding unless the Management Committee determines that the suspension will imperil the stability or reliability of the bulk power supply of NEPOOL

(3) **Aggrieved Participant Options**: The aggrieved Participant's notice to the Management Committee shall invoke arbitration as described herein in its notice pursuant to paragraph B(1), and may also initiate mediation with the agreement of the Management Committee, while reserving the Participant's right to proceed with the arbitration if mediation does not resolve the matter within 20 calendar days of the giving of the Participant's notice or such longer period as may be fixed by mutual agreement of the Management Committee and the Participant. Notwithstanding the initiation of mediation, the arbitration proceeding shall proceed concurrently with the selection of the arbitrator pursuant to paragraph C(1).

(4) **Mediation Positions not to be Used Elsewhere**: All mediation proceedings pursuant to this Section are confidential and shall be treated as compromise and settlement negotiations for purposes of applicable rules of evidence.

(5) **Time Limits; Duration**: Any other Participant that wishes to participate in an arbitration proceeding shall give to the Secretary of the Management Committee a signed written notice no later than 10 calender days after the giving of the Participant's notice of arbitration to the Secretary. The arbitration procedure shall not exceed 90 calendar days from the date of the aggrieved Participant's notice invoking arbitration to the arbitrator's decision unless the parties agree upon a longer or shorter time. All agreements by the aggrieved Participant and Management Committee to use mediation shall establish a time frame which will control unless later changed by mutual agreement.

Arbitration:

(1) **Selection of Arbitrator**: The aggrieved Participant and the Management Committee shall attempt to choose by mutual agreement a single neutral arbitrator to hear the dispute. If the Participant and Management Committee fail to agree upon a single arbitrator within ten calendar days of the giving of the Participant's notice of arbitration to the Secretary, the American Arbitration Association shall be asked to appoint an arbitrator. In either case, the arbitrator shall be knowledgeable in matters involving the electric power industry including the operation of control areas and bulk power systems and shall not have any substantial business or financial relationships with NEPOOL or its Participants (other than previous experience as an arbitrator) unless otherwise mutually agreed by the aggrieved Participant and the Management Committee.

(2) **Costs**: Each party shall be responsible for the following costs, if applicable:

(i) its own costs incurred during the arbitration process (except that this does not preclude billing the aggrieved Participant for its share of NEPOOL Expenses that may include the Management Committee's costs); plus

(ii) One half of the common costs of the arbitration including, but not limited to, the arbitrator's fee and expenses, the rental charge for a hearing room and the cost of a court reporter and transcript, if required.

(3) **Hearing Location**: Unless otherwise mutually agreed, the site for all arbitration hearings shall be NEPOOL's headquarters.

Rules and Procedures:

(1) **Procedure and Discovery**: The procedural rules (if any), the conduct of the arbitration and the availability, extent and duration of pre-hearing discovery (if any) shall be determined by the arbitrator in his/her sole discretion at or prior to the initial hearing, subject to the condition that discovery will be kept to the minimum necessary to resolve the particular dispute.

(2) **Pre-hearing Submissions**: The aggrieved Participant shall provide the arbitrator with a brief written statement of its complaint and a statement of the remedy or remedies it seeks, accompanied by copies of any documents or other material it wishes the arbitrator to review. The Management Committee will provide the arbitrator with a copy of this Agreement and all relevant implementing documents, a brief description of the action being arbitrated, copies of the minutes of all Committee meetings at which the matter was discussed, a brief statement explaining why the Management Committee believes its decision should be upheld by the arbitrator, and copies of any documents or other material the Management Committee wishes the arbitrator to review. These submissions shall be made within five days after the selection of the arbitrator.

In addition, each party shall designate one or more individuals to be available to answer questions the arbitrator may have on the documents submitted. The answers to all such questions shall be reduced to writing by the party providing the answer and a copy shall be furnished to the other party.

(3) **Initial Hearing**: An initial hearing will be held no later than 10 days after the selection of the arbitrator and shall be limited to issues raised in the pre-hearing

filings. The scheduling of further hearings at the request of either party or on the arbitrator's own motion shall be within the sole discretion of the arbitrator.

(4) **Decision**: The arbitrator's decision is due, unless the deadline is extended by mutual agreement of the aggrieved Participant and the Management Committee, within 60 days of the initial hearing or within 90 days of the aggrieved Participant's initiation of arbitration, whichever occurs first. The arbitrator shall be authorized only to interpret and apply the provisions of this Agreement and the arbitrator shall have no power to modify or change the Agreement in any manner.

(5) **Effect of Arbitration Decision**: The decision of the arbitrator will be conclusive in a subsequent regulatory or legal proceeding as to the facts determined by the arbitrator but will not be conclusive as to the law or constitute precedent on issues of law in any subsequent regulatory or legal proceedings.

As aggrieved party may initiate a proceeding with a court or with the FERC with respect to the arbitration or arbitrator's decision only:

if the arbitration process does not result in a decision within the time period specified and the proceeding is initiated within 30 days after the expiration of such time period; or

on the grounds specified in Sections 10 and 11 of Title 9 of the United States Code for judicial vacation or modification of an arbitration award and the proceeding is initiated within 30 days of the issuance of the arbitrator's decision.

Other Disputes:

In the event a dispute arises with a Non-Participant which receives or is eligible to receive service under this Agreement or the NEPOOL Open Access Transmission Tariff with respect to such service, the Non-Participant shall have the right to have the dispute considered by the Management Committee. In the event the Non-Participant is aggrieved by the Management Committee's vote on the dispute, and the vote has any of the effects specified in paragraph A above, the aggrieved Non-Participant may require that the dispute be resolved in accordance with this Section. To the extent that NEPOOL provides services to Non-Participants under separate agreements, the Management Committee shall incorporate the provisions of this Section by reference in any such agreement, in which case the term "Participant" shall be deemed for purposes of the dispute resolution provisions to include such non-Participant purchasers of NEPOOL services

II.A.2.b NEPOOL Executive Committee

Role Of Committee - The NEPOOL Executive Committee will continue to be the executive representation of the NEPOOL Management Committee. Their charge is similar to that of the NMC and thus they are responsible for implementing, administering and changing the provisions of the NEPOOL Agreement.

Committee Representation - The NEPOOL Executive Committee shall be constituted as follows: each Participant whose Voting Share equals or exceeds three percent of the aggregate NMC Voting Shares of all Participants will have the right to appoint a member to the Committee. The remaining Participants will be divided into the following five groups, each group will have the right to appoint one member to the Committee:

(a) One group consisting of the remaining Participants who are municipally-owned and cooperatively-owned utilities;

(b) One group consisting of the remaining Participants who are engaged in New England principally in the business of owning or operating generation and selling the output of such generation;

(c) One group consisting of the remaining Participants who are engaged in New England principally in the business of marketing and/or brokering of electricity or purchasing and resale at wholesale or purchasing at wholesale and resale at retail of electricity; and

(d) One group consisting of the remaining Participants who are solely small regional transmission providers and not involved in any market activity either directly or indirectly. These Participants have no affiliates or related companies in any other subgroups.

(e) One group consisting of the remaining Participants who are investor-owned utilities or who do not qualify to be included in any of the other four groups.

Companies who wish to separately vote their transmission and market interest may split their single NEC vote (including the 5% portion of the vote that is based on Entity status) to two fractional percentages that sum to one. This split voting mechanism will also apply to the MOC, MRPC, RTOC and the RTPC. For companies who choose this voting method, 2 representatives will attend the meeting. This process will ensure that vertically integrated utilities that are functionally unbundled can vote their business interest while complying with the FERC Standards of Conduct.

Additionally, a Participant may elect to join a different group than the one to which it would be assigned under the foregoing provisions as long as this is acceptable to the members of the group it elects to join.

Finally, in the event a Participant is a Related Person of another Participant which has the right to appoint a member to the Committee (separate seat due to being 3% or greater of NMC vote), the Participant shall be represented in the Committee by the related member appointed by the Participant.

The changes proposed here will modify the provisions of the NEPOOL Executive Committee voting by expanding the Committee to include representatives for independent power producers, and for power marketers, brokers, and load aggregators, and small transmission companies; allows for the split of the NEC vote between market and transmission interest; and finally allows a Participant to elect to join a different group.

Voting Structure - Passage of an action item at the NEC will require affirmative votes of 60% of the members present. By changing the threshold needed to pass a vote (60% from 66%), the existing balance between ensuring a majority vote and minimizing the risk of committee gridlock is maintained, because of the addition of three more small group votes.

Dispute Resolution - Each participant will have the right to appeal any NEPOOL Executive Committee Vote to the NMC. Rules defining the appeal and arbitration process are defined under NMC Dispute Resolution section of this proposal.

II.A.2.c Market Operations Committee

Role Of Committee - The Market Operations Committee will be responsible for the development and implementation of the market operations and settlement functions of

NEPOOL. To accomplish this task, the MOC must develop detailed operational rules for the bulk power system and related settlement procedures that will be implemented by the ISO. We envision that existing CRS and NABs procedures will be reviewed and modified by the MOC to accommodate the future NEPOOL structure proposed in this document. The MOC will review and be responsible for implementing market rule changes that may arise from the ISO's assessment of the market operations.

Committee Representation - The Market Operations Committee will be constituted as follows: each Participant whose NMC Voting Share equals or exceeds three percent has the right to appoint one member to the committee. Each Participant whose Voting Share equals or exceeds fifteen percent of the aggregate NMC Voting Shares has the right, so long as such condition continues, to appoint one additional member. However, no one entity or related entity will have more than two members on this Committee. The remaining Participants will be divided into the following five groups, each group has the right to appoint one member on the Operations Committee:

(a) One group consisting of the remaining Participants who are municipally-owned and cooperatively-owned utilities;

(b) One group consisting of the remaining Participants who are engaged in New England principally in the business of owning or operating generation and selling the output of such generation;

(c) One group consisting of the remaining Participants who are engaged in New England principally in the business of marketing and/or brokering of electricity

or purchasing and resale at wholesale or purchasing at wholesale and resale at retail of electricity; and

(d) One group consisting of the remaining Participants who are solely small regional transmission providers and not involved in any market activity either directly or indirectly. These Participants have no affiliates or related companies in any other subgroups.

(e) One group consisting of the remaining Participants who are investor-owned utilities or who do not qualify to be included in any of the other four groups.

Companies who wish to separately vote their transmission and market interest may split their single MOC vote to two fractional percentages that sum to one. For companies who choose this voting method, 2 representatives will attend the meeting. This process will ensure that vertically integrated utilities that are functionally unbundled can vote their business interest while complying with the FERC Standards of Conduct.

Additionally, a Participant may elect to join a different group than the one to which it would be assigned under the foregoing provisions if this is acceptable to the members of the group it elects to join.

Finally, in the event a Participant is a Related Person of another Participant which has the right to appoint a member to the Committee (separate seat due to being 3% or greater of NMC vote), the Participant shall be represented in the Committee by the related member appointed by the Participant.

The changes proposed here will modify the provisions of the NEPOOL Operation Committee voting allowing a Participant to appoint two members of the Committee; expands the

Committee to include representatives for independent power producers, for power marketers, brokers, load aggregators, and small transmission companies; allows for the split of the MOC vote between market and transmission interest; and finally allows a Participant to elect to join a different group.

Voting Structure- Passage of an action by the MOC will require affirmative votes of 60% of the votes present. Similar to the NEC voting, the change in the threshold needed to pass a vote (60% from 66%), maintains the existing balance between ensuring a majority vote and minimizing the risk of committee gridlock (recognizing the additional seats added to the committee).

Dispute Resolution - Each participant will have the right to appeal any Market Operations Committee Vote, to the NMC. Rules defining the appeal and arbitration process are defined under NMC Dispute Resolution section of the report.

II.A.2.d Market Reliability Planning Committee

Role Of Committee - The Market Reliability Planning Committee will be responsible for developing and implementing policy and planning objectives of NEPOOL. Proposed work assignments include coordination with the ISO to perform long term load forecasts; regional installed capacity requirement determination and assessment of assumed parameters; issuance of certain reports and regulatory filings; assessment of future air emissions, and risk profile reliability assessment for the region. The MRPC will review and be responsible for implementing market rule changes that may arise from the ISO's assessment of the market planning functions or regional resource adequacy.

Committee Representation - The Market Reliability Planning Committee shall be constituted as follows: each Participant whose Voting Share equals or exceeds three percent of the aggregate NMC Voting Shares of all Participants will have the right to appoint a member to the Committee. The remaining Participants will be divided into the following five groups, each group will have the right to appoint one member to the Committee:

(a) One group consisting of the remaining Participants who are municipally-owned and cooperatively-owned utilities;

(b) One group consisting of the remaining Participants who are engaged in New England principally in the business of owning or operating generation and selling the output of such generation;

(c) One group consisting of the remaining Participants who are engaged in New England principally in the business of marketing and/or brokering of electricity or purchasing and resale at wholesale or purchasing at wholesale and resale at retail of electricity; and

(d) One group consisting of the remaining Participants who are solely small regional transmission providers and not involved in any market activity either directly or indirectly. These Participants have no affiliates or related companies in any other subgroups.

(e) One group consisting of the remaining Participants who are investor-owned utilities or who do not qualify to be included in any of the other four groups.

Companies who wish to separately vote their transmission and market interests may split their single MRPC vote to two fractional percentages that sum to one. For companies who

choose this voting method, 2 representatives will attend the meeting. This process will ensure that vertically integrated utilities that are functionally unbundled can vote their business interest while complying with the FERC Standards of Conduct.

Additionally, a Participant may elect to join a different group than the one to which it would be assigned under the foregoing provisions as long as this is acceptable to the members of the group it elects to join.

Finally, in the event a Participant is a Related Person of another Participant which has the right to appoint a member to the Committee (separate seat due to being 3% or greater of NMC vote), the Participant shall be represented in the Committee by the related member appointed by the Participant.

The changes proposed here will modify the provisions of the NEPOOL Policy Planning Committee voting by expanding the Committee to include representatives for independent power producers, and for power marketers, brokers, and load aggregators, and small transmission companies; allows for the split of the MRPC vote between market and transmission interest; and finally allows a Participant to elect to join a different group.

Voting Structure- Passage of an action item by the MPPC will require affirmative votes of 60% of the votes present. Similar to the NEC and MOC, the change in threshold needed to pass a vote (60% from 66%), will maintain the existing balance between ensuring a majority vote and minimizing the risk of committee gridlock recognizing the additional seats added to the committee.

Dispute Resolution - Each Participant will have the right to appeal any Market Reliability Planning Committee Vote, to the NMC. Rules defining the appeal and arbitration process are defined under NMC Dispute Resolution section of this proposal.

II. A. 2.e Regional Transmission Planning Committee

Role Of Committee - The RTPC will be the focal point for coordinated transmission planning to meet the regional needs of entities using NEPOOL Participants' transmission services. The mission of the RTPC is to actively and continuously promote the reliability, efficient use and necessary expansion of the transmission facilities of NEPOOL Participants. The RTPC shall take such actions as necessary to provide for the effective coordination of providers' transmission planning activities and the coordination of planning activities under the NEPOOL Agreement with other regional entities, including other control areas, the ISO, the New England states and all appropriate regulatory agencies. The RTPC will review and be responsible for implementing transmission rule changes that may arise from the ISO's assessment of the regional transmission adequacy.

Committee Representation -The RTPC shall be constituted as follows: each Participant whose Voting Share equals or exceeds three percent of the aggregate NMC Voting Shares of all Participants will have the right to appoint a member to the Committee. The remaining Participants will be divided into the following five groups, each group will have the right to appoint one member to the Committee:

(a) One group consisting of the remaining Participants who are municipally-owned and cooperatively-owned utilities;

(b) One group consisting of the remaining Participants who are engaged in New England principally in the business of owning or operating generation and selling the output of such generation;

(c) One group consisting of the remaining Participants who are engaged in New England principally in the business of marketing and/or brokering of electricity or purchasing and resale at wholesale or purchasing at wholesale and resale at retail of electricity; and

(d) One group consisting of the remaining Participants who are solely small regional transmission providers and not involved in any market activity either directly or indirectly. These Participants have no affiliates or related companies in any other subgroups.

(e) One group consisting of the remaining Participants who are investor-owned utilities or who do not qualify to be included in any of the other four groups.

Companies who wish to separately vote their transmission and market interests may split their single RTOC vote to two fractional percentages that sum to one. For companies who choose this voting method, 2 representatives will attend the meeting. This process will ensure that vertically integrated utilities that are functionally unbundled can vote their business interest while complying with the FERC Standards of Conduct.

Additionally, a Participant may elect to join a different group than the one to which it would be assigned under the foregoing provisions as long as this is acceptable to the members of the group it elects to join.

Finally, in the event a Participant is a Related Person of another Participant which has the right to appoint a member to the Committee (separate seat due to being 3% or greater of NMC vote), the Participant shall be represented in the Committee by the related member appointed by the Participant.

Voting Structure - Passage of an action item at the RTPC will require affirmative votes of 60% of the members present. Setting the threshold needed to pass a vote at 60% will ensure a majority vote and minimize the risk of committee gridlock.

Dispute Resolution - Each Participant will have the right to appeal any Regional Transmission Planning Committee Vote, to the NMC. Rules defining the appeal and arbitration process are defined under NMC Dispute Resolution section of this proposal.

II. A. 2.f Regional Transmission Operations Committee

Role Of Committee - The Regional Transmission Operations Committee will be responsible for overseeing and amending the regional transmission tariff, developing rules for pricing transmission services, and providing the rules governing operation of the transmission system. The RTOC shall take such actions as necessary to provide for the effective coordination of providers' transmission operational activities and the coordination of operational activities under the NEPOOL Agreement with other regional entities, including other control areas, the ISO, the New England states and all appropriate regulatory agencies. The RTOC will review and be responsible for implementing transmission rule changes that may arise from the ISO's assessment of the regional transmission operating rules.

Committee Representation -The RTPC shall be constituted as follows: each Participant whose Voting Share equals or exceeds three percent of the aggregate NMC Voting Shares of all

Participants will have the right to appoint a member to the Committee. The remaining Participants will be divided into the following five groups, each group will have the right to appoint one member to the Committee:

(a) One group consisting of the remaining Participants who are municipally-owned and cooperatively-owned utilities;

(b) One group consisting of the remaining Participants who are engaged in New England principally in the business of owning or operating generation and selling the output of such generation;

(c) One group consisting of the remaining Participants who are engaged in New England principally in the business of marketing and/or brokering of electricity or purchasing and resale at wholesale or purchasing at wholesale and resale at retail of electricity; and

(d) One group consisting of the remaining Participants who are solely small regional transmission providers and not involved in any market activity either directly or indirectly. These Participants have no affiliates or related companies in any other subgroups.

(e) One group consisting of the remaining Participants who are investor-owned utilities or who do not qualify to be included in any of the other four groups.

Companies who wish to separately vote their transmission and market interests may split their single RTOC vote to two fractional percentages that sum to one. For companies who choose this voting method, 2 representatives will attend the meeting. This process will ensure

that vertically integrated utilities that are functionally unbundled can vote their business interest while complying with the FERC Standards of Conduct.

Additionally, a Participant may elect to join a different group than the one to which it would be assigned under the foregoing provisions as long as this is acceptable to the members of the group it elects to join.

Finally, in the event a Participant is a Related Person of another Participant which has the right to appoint a member to the Committee (separate seat due to being 3% or greater of NMC vote), the Participant shall be represented in the Committee by the related member appointed by the Participant.

Voting Structure - Passage of an action item at the RTOC will require affirmative votes of 60% of the members present. Setting the threshold needed to pass a vote at 60% will ensure a majority vote and minimizes the risk of committee gridlock.

Dispute Resolution - Each Participant will have the right to appeal any Regional Transmission Operations Committee Vote, to the NMC. Rules defining the appeal and arbitration process are defined under NMC Dispute Resolution section.

II. B. The Independent System Operator

Our ISO proposal is consistent with the FERC principles articulated in Order 888, while going several steps further to ensure the independence and neutrality of the ISO. We believe that an ISO should be an independent, neutral implementer of the rules established by the NEPOOL Participants with the assistance and input of the ISO and approved by the FERC. The primary purpose of the ISO will be to ensure the reliability of the electric system, and to operate the system and administer the market and the applicable transmission tariffs in an efficient,

economic and non-discriminatory manner. The following sections discuss the independence and neutrality of the ISO, its roles and responsibilities in transmission and generation, its administration of a power exchange and its duties with respect to information control.

II. B. 1. Independence and Neutrality of the ISO

To ensure its independence, the ISO will be a separate legal entity that will have employees who are independent from any NEPOOL or market participant. The ISO and its directors, officers and employees will have no financial interest in the economic performance of any market participant and will not transact for their own benefit in the NEPOOL electricity market. The ISO will be a non-profit, non-stock corporation. This form of entity is preferable to a for-profit corporation because it is more likely to maintain the neutrality of the ISO. Additionally, a for-profit form is not necessary to create performance incentives for the ISO, because these incentives can be written into the contractual arrangement between the ISO and NEPOOL. Despite being incorporated under and therefore subject to the corporate laws of a particular state, the ISO will also be subject to FERC jurisdiction under 16 U.S.C. §§ 824 and 824d, in that it will affect a rate in connection with the transmission or sale of electric energy in interstate commerce.

Also to ensure its independence, the ISO will have a board of directors that will not be controlled by any participant or class of participants. Nor will any market participant be a member of the board. The board's primary mission will be to ensure that the ISO staff is operating the system in a reliable, efficient and non-discriminatory manner consistent with the rules provided to the ISO. There will be a mechanism for market participants to provide feedback

on ISO performance to the board. There will also be a dispute resolution mechanism to resolve disputes between market participants and the ISO.

The initial board will be selected by NEPOOL Participants from a group of candidates that have been pre-qualified by a professional search firm. The board should contain a cross-section of relevant skills and experience, including at least some members who have prior electric industry experience. There should be some mechanism, such as a bylaw, for ensuring that this cross section of skills and experience is maintained through successive board members. The Board will be self-perpetuating after initial selection, and Board members will only be dismissed for cause. Once the initial Board is selected and employed under an interim contract with the NEPOOL Participants, it will assist them in developing the rules that will govern the daily operation of the regional electric system and the power exchange. The initial Board will also negotiate with NEPOOL Participants the terms and conditions of the final NEPOOL/ISO contract.

To further ensure its independence and the efficient and competitive functioning of the NEPOOL electricity market, the ISO will have authority to perform independent assessment and planning of the interconnected regional electric system, and independent assessment of the NEPOOL market.

To ensure its neutrality and independence, the ISO should not be a market participant, except to the extent necessary to ensure reliability. The ISO should simply facilitate the market by being a neutral and reliable implementer of rules consistent with its contractual arrangement with NEPOOL.

II. B. 2. ISO Roles and Responsibilities with Respect to Transmission

The ISO will control the operations of the transmission system consistent with its contract with market participants. It will oversee the security, reliability and efficient functioning of that system. The ISO will have at least the following operational responsibilities with respect to the transmission system: (1) the ISO will coordinate voltage and VAR dispatch with satellites, generation operators and substation operators; (2) the ISO will monitor flows on all lines 115kV and above, all inter-pool transmission facilities, and all facilities associated with predetermined inter-area power flows; (3) the ISO will direct operations to return system operations to normal following a system disturbance; (4) the ISO will oversee restoration procedures after a partial or full system blackout; and (5) the ISO will maintain a database and line ratings for transmission lines.

The ISO should not own or lease the transmission facilities. ISO ownership or leasing of the transmission facilities would raise difficult property, financing, and other legal issues, and would slow the evolution of the regional electric industry, without providing any incremental benefit beyond operational separation. Neutrality concerns as well as legal issues also strongly suggest that the ISO should not have the responsibility for setting transmission rates. These rates will be established by tariffs filed by the transmission providers and the Regional Transmission Operations Committee and approved by the FERC. The ISO should simply implement and enforce these tariffs. System planning, evaluation and forecasting will be done by the ISO both at direction of NEPOOL Participants and on its own initiative.

II. B. 3. ISO Roles and Responsibilities with Respect to Generation

The owners of generation should operate their facilities under the coordinated direction of the ISO. The ISO should direct the operation of the generation system in a manner that ensures the efficiency and reliability of the system, taking into account any transmission constraints. A system of central dispatch that gives Participants a limited right to self-schedule their resources, provides the most reliable and efficient regional electric system.

The ISO should have at least the following specific responsibilities with respect to the generation system: (1) unit commitment and decommitment; (2) operation of interconnections with external systems; (3) maintenance of operating limit data for all units under its direct generation control; (4) evaluation and modification, as required, of the control modes and incremental loading of generating units to ensure and optimize system reliability, operating reserve, AGC requirements and economics; (5) management of control area interchange and inadvertent power with external systems; (6) maintenance of sufficient operating reserves to comply with NPCC and NERC guidelines; (7) operation and administration of the Hydro Quebec Phase I/II Interconnection; (8) coordination of the Highgate power transactions with the VELCO dispatcher; (9) management of automatic generation control; (10) performance of real time economic dispatch; (11) coordination with satellites of small unit dispatch; (12) coordination of New England hydro schedules (the relative roles of the ISO and the owners of hydro and pumped storage with respect to scheduling is an issue that needs further discussion); (13) operation of the system under unusual or emergency conditions; and (14) coordination of maintenance scheduling consistent with system reliability and the contractual arrangement between the ISO and NEPOOL. The ISO staff will have a role in conducting load forecasts, resource adequacy studies

and calculations of objective capability, which will be done at the direction of the NEPOOL committees.

The satellites will eventually be eliminated and most of their functions will be done by the ISO. However, because of the significant complexity and cost involved in making this change, the satellites will remain in existence for at least the next few years, subject to operational separation between the regulated and deregulated functions and appropriate standards of conduct. Until the satellites are eliminated, the ISO will have the authority and the responsibility for monitoring their compliance with appropriate standards of conduct.

II. B. 4. Power Exchange Within the ISO

Spot markets for electricity products should be established as soon as is practicable. The development of spot markets with visible market pricing will benefit customers in a number of ways. It will encourage new entrants into the market, because they will know the market clearing price and therefore will be able to more accurately project revenue streams. More players in the market means greater customer choice. Spot markets will also enhance customer choice in an open access retail environment by giving customers a default supplier. Finally, spot market pricing will reward efficient production of electricity, and thereby provide a substantial incentive to generation owners to lower costs.

There will be separate product markets for energy, capacity and ancillary services with bidding and visible clearing prices for each of these separate product markets. These spot markets will serve as a default mechanism for market participants who cannot provide these products out of their own resources or through bilateral transactions. They will also serve as a source of power for wholesale customers who have not made other arrangements.

We believe that the power exchange should exist within and be administered by the ISO rather than making the power exchange a separate entity, because: (1) we believe that combining the power exchange functions--such as bid-taking, calculating the market clearing prices and settling the market transactions--with the ISO functions creates a more efficient and reliable system; and (2) we see no need to separate the power exchange from the ISO. Additionally, we believe that the creation of a separate power exchange will require substantially more time, effort and expense than creating a power exchange within the ISO, and has virtually no chance of being done by January 1, 1998. The incorporation of the power exchange into the ISO will not give preferential treatment to one market participant over others, as some have suggested, because the power exchange will not be a market participant. Instead, the power exchange simply will be a part of the market infrastructure designed to facilitate market transactions.

Because the ISO has two primary functions (to operate the bulk power/transmission system and to facilitate market transactions by administering the power exchange), these two functions will require separate staffs with separate sets of skills and knowledge. Accordingly, the ISO will contain within its corporate structure separate departments that will perform these functions and that will report up to separate managers, who in turn will report up to the ISO Chief Executive Officer.

II. B. 5. The ISO and Information Control

The ISO will handle market information it receives from NEPOOL participants in accordance with the NEPOOL Information Policy and appropriate standards of conduct. Information furnished to the ISO and designated as confidential shall not be disclosed to anyone else unless the furnishing participant authorizes such disclosure, or a governmental body with appropriate jurisdiction orders such disclosure. The ISO will disseminate all non-confidential information on a non-discriminatory basis and will operate an electronic information network (OASIS) consistent with the requirements of FERC Order 889.

II. C. The NEPOOL/ISO Contract

The contract between NEPOOL and the ISO will contain at least the following general elements.

The contract will contain a definition section covering key terms, so that all Participants can be clear about the meaning of those terms as used in the various NEPOOL agreements.

The contract will define the respective rights and obligations of the ISO and NEPOOL, including provisions setting forth the scope of the ISO's authority.

The contract will provide the standards of conduct, either by explicitly containing them or by incorporating them by reference to another document, governing the ISO's interaction with market participants. We believe the ISO should be given clear direction as to restrictions on that interaction, taking into account the practical realities of operating the system.

The contract will contain a provision that will describe how the ISO budget will be established and how it will be funded.

The contract will contain a provision governing indemnification of the ISO and the scope of its liability to NEPOOL and the type and amount of insurance it must carry.

The contract will contain a termination provision that will detail events of default, the right to cure and the notice period for exercising the termination right.

There will be a dispute resolution provision in the contract that will, to the extent possible, coincide with the dispute resolution provision in the NEPOOL Agreement.

There will be a governing law provision.

The NEPOOL/ISO contract will be subject to the jurisdiction of the FERC under 16 U.S.C. §§ 824 and 824d, in that it will affect a rate in connection with the transmission or sale of electric energy in interstate commerce. The contract will be amended as necessary through the NEPOOL voting structure subject to FERC approval.

III. Market Operations

III. A. Overview

As discussed in Section II of this document, we propose that NEPOOL be comprised of Market Committees and Regional Transmission Committees. This section describes proposed modifications to the NEPOOL market rules.

Currently under the NEPOOL Agreement, the New England electric utilities have agreed to physically operate the bulk power system in an integrated fashion. In doing so, the Participants have gained many synergies including reduced installed capacity requirements (reliability efficiency) and reduced energy costs from the central dispatch (economic efficiency). Allocation of the regional responsibilities to the Participants, involve the placing of requirements on the Participants. The mechanisms developed to allocate requirements and measure

performance of the Participant against the requirement include many subsidies and protections against unforeseen occurrences. In the event a Participant is deficient in meeting a requirement, the enforcement actions by NEPOOL involve penalizing those who do not meet their obligations.

Participant requirements imposed by the NEPOOL Agreement include installed capacity, energy, operating reserves and Automatic Generation Control (AGC). Participants have met these requirements through ownership of resources or through bilateral contracts. Measurement of the Participants' performance in meeting the requirements to date, has been done through the NEPOOL Capability Responsibility formula, the own load energy billing process and the AGC billing process.

To achieve the goal of a competitive restructured electric industry, we propose modifying the market rules in the NEPOOL Agreement according to the following general principles:

- NEPOOL will continue to operate its generation and load in an integrated fashion to ensure continued reliability and economic efficiency.
- NEPOOL regional requirements for capacity, energy and ancillary services will be allocated to NEPOOL Participants in a fair and non-discriminatory manner.
- Penalties will be replaced with spot markets so that market players can choose to own resources, bilaterally contract for them, or rely on the spot market to meet their capacity, energy or ancillary services requirements.
- Each spot market will have a visible spot price.

- Market rules allocating requirements and measuring Participant performance must ensure comparability in their treatment of Participants and their resources and eliminate subsidies that now exist.
- The new market structure cannot jeopardize system reliability or create unacceptable market power concentrations. If these problems develop, mitigating measures must be adopted.

We propose that these principles are best met through the development of seven spot markets. The spot markets include installed capacity, operable capacity, energy, 10 minute spinning reserve, 10 minute non spinning reserve, 30 minute reserve and AGC. Acknowledging the difficulty and complexity of developing these markets, we propose a three step process to accomplish the task. First, we need to develop the most efficient market structure to meet each requirement. Second, we need to analyze the market structures to ensure they do not create market power concentrations or system reliability concerns. Finally, if the market structures do create market power concentrations or reliability concerns, we need to develop solutions to mitigate those concerns. We believe this structure and process best meet the principles outlined above for the future electric market.

The following sections provide a more detailed description of the market requirements and rules including more information on the structure of the seven proposed market.

III. B. Installed Capacity

III. B. 1. Overview

The following Section details the changes proposed in the Installed Capacity Requirements of NEPOOL. The section gives a brief overview of the obligation, then examines

the calculations, allocations and mechanisms needed to meet the obligation and to achieve the separation from other products and transmission requirements for installed capacity trading. Additionally, in the section on Meeting Installed Capacity Requirements, we propose a mechanism to achieve a spot market with a visible price signal for Installed Capacity trading. This spot market mechanism will eliminate the present penalty mechanism for Participants who are deficient in installed capacity in any given month.

III. B. 2 Installed Capacity Obligation

Ensuring regional reliability is a primary objective of the electric industry restructuring process. In order to ensure North American Electric Reliability Council (NERC) system reliability standards will continue to be met regionally in the new industry structure, a regional requirement for capacity installed within the NEPOOL control area will be maintained. The installed capacity requirement will continue to be allocated to the load serving NEPOOL Participants, which will effectively obligate those entities to own or contract for installed capacity rights within the region. The mechanisms used to calculate, allocate and measure this requirement will be modified from today's NEPOOL installed capacity requirement to reflect the numerous changes in the industry structure, the desire to create competitive spot markets in place of penalty mechanisms and ensure comparability between all market participants. The following section details the installed capacity obligation calculation, allocation and measurement for the restructured NEPOOL.

III. B. 3. Regional Installed Capacity Requirement Calculation

III. B. 3.a NEPOOL Today

Currently, NEPOOL plans the generation system to meet the 1 day in 10 year loss of load probability criterion dictated by the NERC. The process of determining generation requirements is model-based and considers system characteristics such as firm load projections; generating unit capacity and availability characteristics; contract sales and purchases with entities outside the region; tie line benefits that result from being interconnected to other control areas; and emergency actions that can be taken when capacity shortages occur. The result of this calculation is a target amount of installed capacity needed within the NEPOOL control area, designated NEPOOL Objective Capability.

III. B. 3.b Restructuring Proposal

The future regional installed capacity requirement calculation will continue similar to today's calculation. As the industry restructuring continues to evolve and the proposed markets mature, the need and process for setting the installed requirement should be examined, and where possible simplified.

- *Requirement Determination* - The installed capacity requirement will be calculated by the ISO in accordance with the rules established by NEPOOL.
- *Requirement Time Frame* - The installed capacity requirement will be calculated and set for a 3-6 year period with milestone reviews annually of critical input assumptions.
- *Requirement Model Used* - The installed capacity requirement determination will continue to be a model-based calculation using the Westinghouse Capacity model.
- *Firm Load Forecast Used* - The ISO will annually generate a weekly firm load forecast (formatted to fit model requirements), which will be used to calculate the installed capacity requirement.

- *Generation Ratings Used* - The generation capacity ratings used to calculate the installed requirements will be based on the generator's maximum claimed capability demonstrated achievable to the ISO in its audits of capacity.
- *Generation Availability Used* - The generation scheduled and unscheduled outage rates used in calculating the installed capacity requirement will be based on the NEPOOL Market Operations Committee's and the ISO's best estimates of availabilities for generation.
- *Contract Purchases/Sales With Entities Outside Control Area* - In determining the regional installed capacity requirement, all firm capability contracts will be considered.
- *Interconnection Benefits* - The assumed full benefits from being interconnected to other regions used in determining the installed capacity requirement will be based on the Market Reliability Planning Committee's and the ISO's best estimate of emergency assistance available to NEPOOL from neighboring pools.
- *Projected Capacity Benefits from Emergency Actions* - The ISO will annually issue expected capacity benefits from emergency procedures taken during a capacity deficiency (OP4 Actions). This value will be used in determining the regional installed capacity requirement.

Established studies, CRS's and NAB's rules can (where appropriate) be the basis of interim requirement guidelines. A future step of the restructuring process should examine the relevant NEPOOL CRS's for NEPOOL's installed capacity requirement and modify them to fit the future needs of the industry.

III. B. 4 Regional Installed Capacity Requirement Allocation

III. B. 4.a NEPOOL Today

Once regional capacity requirements are established, the regional capacity need must be allocated to the NEPOOL firm load serving Participants in a fair and equitable manner. Currently, Participants are allocated their share of the installed capacity requirement and are required to maintain this level for every hour of the month. The existing allocation is based primarily on the following 5 factors and is called Participant's Capability Responsibility (CR):

- Participants' 16 month historical ratcheted peak load compared to the projected sum of all Participants' ratcheted peak loads (70 portion of 70/30 Formula)
- Participant' 12 month average peak load compared to projected sum of all Participants 12 month average peak loads (30 portion of 70/30 Formula).
- The 4 year average historical performance of generation owned or under contract (PIP Program), adjusted for the impact of an extreme generator outage on any other single entities system (Safety Net)
- The units or contracts calculated impact on the reliability calculation (New Unit Program).

In addition to these factors, some other attributes exist in today's allocation of the installed capacity requirement that are modified in this proposal. First, because the capacity benefits received from having interconnections with other control areas are used to reduce regional capacity needs (thus shared by load servers), there exists no recognition of transmission owners' roles in providing these benefits. In some instances the capacity benefits received via a transmission line far exceed the transmission owner's load affiliate firm load requirements and thus allocated share of tie benefits.

Second, capacity purchases that are made across tie lines from other control areas reduce the amount of tie line benefits that can be received in an emergency situation. Since tie benefits are used to reduce regional requirements, any reduction in tie benefits will increase the amount of installed capacity needed in the NEPOOL control area. The changes in regional installed capacity need due to contracts over tie lines are measured in the Tie Line Adjustment Calculation. The net effect of the program is that any single Participant's contract over the tie lines will benefit/burden the region as a whole. There currently exist no mechanisms to allocate the impact on regional installed capacity needs from contracting over tie lines directly to the contracting Participant.

III. B. 4.b Restructuring Proposal

Given the potential for more dynamic changes in load, the need to ensure comparability in the treatment of market participants' resources and the potential inequities in the present handling of tie lines, changes must be made in the allocation of the NEPOOL regional installed capacity requirement. The allocation to Participants of the installed capacity requirement will still be an obligation to maintain a minimum level of installed capacity in every hour of the month. To simplify terminology, the Participants' allocated share of the regional installed capacity requirements will continue to be called Capability Responsibility and will be calculated with the following methodology.

- *Capability Responsibility (CR)* - will be the Participants' monthly allocation of regional installed capacity requirement, allocated to the firm load serving Participants within NEPOOL. Each Firm Load Serving Participant will have an obligation to maintain (own,

contract for) a determined level of Installed Capacity every hour of the month, as determined by the following formula:

(Equation 1)

Capability Responsibility (CR) $[A / \sum A's] * B$

Where:

A Is the Participants adjusted monthly peak load.

B Is NEPOOL Regional Installed Capacity requirement for the month.

- *Adjusted Monthly Peak Load (A)* - the Participant's greatest hour of firm energy service for the month in which CR is calculated. Firm energy service includes retail firm load, wholesale all or partial requirements contracts and CD contracts, adjusted for any interruptible contracts provided for by the Participants but not interrupted. An actual monthly peak load value will be utilized rather than an historical average, because it provides greater flexibility in allocating installed capacity responsibility in an environment where load service may be shifting between providers from month to month.

- *NEPOOL Regional Installed Capacity Requirement (B)* - This is the ISO forecast of the amount of installed capacity needed in the NEPOOL region in order for NEPOOL to maintain the NERC reliability criterion of 1 day in 10 years.

A few key attributes of this installed capacity allocation mechanism not seen in the formula are as follows:

- *Load Reconstitution* - Currently, in allocating regional capacity requirements, shifts in firm load service from one Participant to another must be addressed by reconstituting both Participants' historical firm loads. In this proposal, using the current month's peak load to calculate the capacity requirements for the month reduces the need for this complex calculation. However, allocation of the capacity requirements for shifts in Firm Load within the month must still be addressed.
- *Incentive For Unit Availabilities* - Currently, the Performance Incentive Program (PIP) provides a feedback mechanism and incentive for good unit operation through capacity adjustments in the CR formula. This mechanism will be eliminated and replaced by incentives for unit operation through the 6 hourly spot markets. A unit which has superior performance will be recognized through revenues received in bilateral transactions or through the spot market transactions. The credits or debits from past performance will be recognized in a transition process to these new rules.
- *Capacity Protection From Catastrophic Outages* - Presently the Safety Net Program apportions the impact of lengthy unit outages among all NEPOOL Participants providing a measured protection for all unit owners. This subsidy will be eliminated and replaced by the operation of markets. A measured amount of protection will be achieved for all Participants, because replacement cost for large outages will be market and not penalty based.
- *Tie Benefit Allocation* - Benefits received from being interconnected to other areas will continue to be allocated to load serving entities. These capacity benefits (Tie Benefits)

will be allocated based on the following formula as it may be revised based on ongoing RTG negotiations (Equation 2):

Tie Benefits Received (TBR) $[A / \sum A's] * TB$

Where:

A Is the Participant's adjusted monthly peak load.

TB Is the Total Monthly Tie Benefits as determined in setting the Regional Installed Capacity Requirement.

Recognition of the tie line owners' contribution to providing these tie benefits will be done as a wheeling payment for the tie benefits to the transmission providers. The NEPOOL transmission provisions will outline the wheeling method. These provisions are discussed in Section IV. B. 2 of this proposal.

- *Allocation of The Impact on Regional Installed Capacity Requirements From Contracting Outside the Control Area* - Each Participant will bear the burden on regional installed capacity requirements of the contracts entered into with others outside the NEPOOL Control Area. The mechanism, still to be developed, to determine this impact will be called the Outside Transaction Adjustment and will consider the size of the contract, the change in regional installed capacity requirements, and the contracting Participant's allocated share of tie benefits. The relationship between Tie Benefits, contract amount and impact on regional capacity requirements will be determined by the ISO in coordination with the NEPOOL Committees, using a pre-approved, standardized methodolgy.

III. B. 5 Meeting Capability Responsibility Requirements

III. B. 5.a NEPOOL Today

A Participant can meet its Monthly CR requirement through direct ownership of generation or through bilateral contracts for installed capacity. In the event a Participant does not acquire adequate resources (is deficient), service is provided through NEPOOL and the Participant pays a Deficiency penalty cost (based on carrying costs of new replacement generation). This deficiency payment is allocated to all Participants providing the surplus installed capacity in the month.

III. B. 5.b Restructuring Proposal

Participants will continue to be able to meet the monthly CR Requirements through ownership of generation or bilateral contracts. However, a Participant will also be able to rely on the spot market for installed capacity to provide all or a portion of their Installed Capacity Requirement (all 3 options available to meet CR will have associated wheeling expenses as outline in the regional transmission proposal). With the addition of a spot market for installed capacity, a Participant will be able to better manage its portfolio of resources and the way in which it meets its CR Requirement. A Participant may choose the potential stability in costs offered through ownership or bilateral contracts, or choose to minimize resource acquisition and be subject to the volatility of the spot market price. In this environment, penalties will be eliminated, but the risks for shortages will be seen through the movement in the market price signal.

To achieve this structure, a spot market for Installed capacity must be implemented by the Market Participants. The characteristics of the spot market should complement the 6 other spot

markets, must continue to allow for bilateral transactions (thus capacity retention) and must include a visible spot price (ICCP).

- *Installed Capacity Spot Market* - To develop a Spot market for Installed Capacity (thus replacing the existing adjustment and deficiency charges that incorporates a penalty mechanism), we propose the following procedure.

Proposed Procedure

Step 1: Entities will submit the amount and price to supply Spot Market Installed Capacity. Prior to each month all suppliers will bid into the ISO any installed capacity with an associated price they are willing to provide to those who choose to buy through the Spot Markets.

Example: Company A Bids 10 MW @ 1.00 $/kW-mo

Company B Bids 10 MW @ 1.10 $/KW-mo

Company C Bids 3 MW @ .50 $/KW-mo

Step 2: The ISO will determine the Clearing Price stack. The ISO will stack bids in ascending order to determine clearing price.

Example: 1-3 MW @ .50 $/KW-mo.

4-13 MW @ 1.00 $/KW-mo.

14-23 MW @ 1.10 $/KW-mo

Step 3: The ISO Will Determine the Spot Market Purchases. After each month, the ISO will determine which Participants bought installed capacity through the spot market, given the proposed monthly CR calculation.

Example: Company D purchases 10 MW on a 100 MW load,

Step 4: The ISO Will Calculate Installed Capacity Clearing Price. Those purchasing installed capacity through the spot market will pay the clearing price for that capacity. The clearing price will reflect a transmission wheeling component payable to the transmission suppliers.

Example: Only 10 MW Purchased, corresponds to 1.00$/kW-mo.

D purchased 10 MW @ 1.00 $/KW-mo = $10,000.00/month + Wheeling

Step 5: The ISO Will determine the distribution of a Clearing Price To Suppliers. All providers get clearing prices.

Example: A gets 7 MW at 1.00 $/KW-mo. = $7000.00/month + Wheeling

C gets 3 MW at 1.00 $/ KW-mo = $3000.00/month + Wheeling

Step 6: The ISO will adjust the Minimum Capacity of suppliers that offer spot market capacity. To maintain appropriate accounting and ensure spot market suppliers have adequate surplus, the ISO will adjust suppliers' minimum capability to reflect the amount of capacity offered through the power exchange.

Example: A- Minimum Capability gets reduced 7 MW

C- Minimum Capability gets reduced 3 MW.

If not enough capacity is bid into the ISO to cover spot market sales, all those requiring additional installed capacity will pay the highest price bid into NEPOOL. Revenues will be split among all bidders in pro rata shares. This should encourage Participants to bid excess capacity into the spot market

If a Participant who supplied capacity into the spot market needs additional installed capacity after the minimum capability adjustment, it will pay the clearing price for the amount needed.

Other mechanical details of the spot market for installed capacity must be resolved. The ISO will administer and settle the spot market trades.

III. B. 6. Bilateral Contracts

Trading of bilateral contracts for capacity will continue similar to today. The notice provisions presently placed on transactions notifying NEPOOL, should be examined and reduced to the lowest possible level that can be administered while not jeopardizing reliability or circumventing the bidding notice provisions.

III. B. 7. Installed Capacity Product Separation

Installed capacity can be traded bundled or separately from all other products.

III. B. 8. Transmission Requirements For Installed Capacity Product

Trading for the Installed Capacity product bilaterally or through the spot market will be in conformance with rules developed in the NEPOOL Committees.

III. C. Energy Market

III. C. 1. Overview

The following Section details the changes proposed in the dispatch operations and settlement of Participant Energy Requirements. It provides a brief overview of the current practices, Participant obligations and proposed changes to economic dispatch and settlement of Participant requirements. Through this presentation, we intend to illustrate the efficiency and equity benefits of an unbundled energy clearing market based on market priced resources.

Appendix 1 provides examples of clearing price determination for energy, automatic generation control, 10 minute spinning reserve, 10 minute non-spin reserve, 30 minute reserve and operable capacity as well as an example of adjusted net interchange ("ANI").

III. C. 2. NEPOOL Today

Today, New England energy needs are economically met through a cost-based central dispatch. Individual Participants are held responsible for acquiring sufficient resources to support their respective energy needs. Participants pool their resources under the NEPOOL Agreement to facilitate a regional dispatch targeted at protecting regional reliability and maximizing regional economy. Allocation of costs and benefits are performed through a combination of participant redispatch and shared savings programs. The intent is to limit differences between actual and redispatched generation to realistic differences between how a Participant would have its resources if it existed independently and the actual NEPOOL dispatch of these units. Experience has taught us, however, that practicality limits NEPOOL's ability to accomplish this ideal comparison. Redispatch modeling unrealistically provides advantages of perfect foresight as well as opportunities to understate fuel costs and exaggerate unit characteristics. Cost impacts of these factors are somewhat mitigated by cost based unit dispatch. Non-mitigated impacts are obscured in the NEPOOL Savings Fund.

III. C. 3. Restructuring Proposal

Our restructuring proposal for energy seeks to maintain the reliability and economy advantages of regional dispatch while modifying the unit costing and settlement systems to accommodate the varied roles of existing and new Participants in the coming years. Under this system, each Participant will continue to be responsible to serve its full energy responsibilities.

Units will be submitted for central dispatch at an energy bid which could be either higher or lower than prior replacement fuel cost. Participants could provide their energy needs through own generation (including unit entitlements), bilateral transactions or purchases through a NEPOOL Energy Clearing Market. The settlement system will evaluate Participant energy needs versus Participant generation or bilateral trades on an hourly basis. Hourly negative imbalances would purchase energy at an Energy Clearing Price (ECP) and positive hourly imbalances would be sold at an Energy Clearing Price. To the extent not all costs are properly accounted for in other aspects of the settlement system, Energy Clearing Price for buyers could also involve an uplift. All efforts will be made to minimize the uplift.

Bid Price Submittal - Every unit will have a bid price on file with the ISO that will be expressed in $/MMBTU and will internalize any recovery of operation and maintenance adders. It will be at the unit owners option to submit revised bids each day.

Day Ahead ISO Dispatch - The ISO will continue to perform a day ahead dispatch simulation considering the system constraints, forecast loads, energy and other bid prices. Participants can use this day ahead dispatch forecast to plan their bilateral transactions and self-scheduling decisions.

Self-Scheduling - Self-scheduling of resources shall be allowed to the extent that it does not create market power or reliability concerns and appropriate rules and standards are implemented to ensure Participant accountability for their self-scheduling of generation resources.

Actual Dispatch - The ISO will physically dispatch resources as necessary to meet load, ensure reliability through maintenance of adequate operating reserves, and produce the least

regional cost across the energy, AGC and operating reserve requirements. An improved dispatch algorithm will be developed to incorporate the new bid price signals for 10 minute spinning reserve, 10 minute non-spin reserve and 30 minute reserve.

Participant Energy Requirement - The Participant Energy Requirement will be equal to the sum of hourly retail load, transmission and/or distribution losses (to be allocated via an agreed upon allocation process), pumping loads associated with pumped storage and bilateral sales to other Participants.

Participant Energy Supply - The Participant Energy Supply will be equal to the actual generation from the Participant's resources, which can be ownership units, entitlements in other's units, plus bilateral system energy purchases .

Energy Clearing Price Determination (ECP) - The ISO will calculate an ECP for each hour. Within each hour, actual generation blocks will be stacked by bid price from lowest to highest. Bid price for these purposes will include an energy component determined by the energy bid price submittal expressed in $/MMBTU and the heat rate corresponding to the actual loading level as well as an allocation of the daily start-up and no load costs.

Energy Settlement - For each hour, the ISO will determine whether a Participant was a net seller or net buyer. If the hourly Participant Energy Supply was less than the hourly Participant Energy Requirement, the Participant would be responsible for paying for the energy purchased at the hourly Energy Clearing Price (ECP). If the hourly Participant Energy Supply exceeded the hourly Participant Energy Requirement, the Participant would receive payment for the level of excess generation at the hourly ECP.

III. D. Automatic Generation Control (AGC)

III. D. 1 Overview

The following Section details the changes proposed in dispatch operations and the allocation of requirements and associated costs of providing frequency regulation and maintenance of proper external tie-line schedules through load changes on units capable of automatic generation control (AGC) . The section provides a brief overview of the current practices, Participant obligations and proposed changes to allocation of AGC requirements and associated costs. Through this presentation we intend to illustrate the efficiency and equity benefits of an unbundled AGC market based on market priced resources.

III. D. 2 NEPOOL Today

Today, dispatchers control regional frequency and maintain proper external tie-line schedules utilizing any one or combination of units capable and available to provide automated generation control. NEPOOL has provided for sufficient supply of AGC capable units by imposing a non-uniform requirement on generators. Unlike energy and operating reserve requirements, AGC requirements are not considered in the redispatch settlement system. A separate adjustment provides a flow through of some AGC related fuel costs to all participants based on Participant load, though it is questionable whether this system is efficient. In an environment of cost-based dispatch and vertical integration of the majority of Participants, the sufficiency and strength of these economic signals has not attracted significant attention. Today's abundant AGC supply is significantly linked to a Participant's obligation to serve loads reliably. Given the future uncertainty regarding who would serve load and who would own generation, a more appropriate and efficient pricing signal will be needed.

III. D. 3 Restructuring Proposal

Our restructuring proposal seeks to create a market driven signal that will encourage the supply of AGC capable units and equitably compensate those units for their contribution. Participants will be allocated an AGC requirement equal to their prorated portion of AGC utilized by NEPOOL on a load basis. This clearing market is intended to compensate AGC providers for the physical ramping of their generation under automatic control within the hour. The compensation for economic backdown within the hour will be accomplished through the 10 minute spinning reserve clearing market. Due to the control nature of this service, its demand uncertainty and lack of direct link to forecast load, this requirement would continue to be absent from the dispatch optimization. Participants would be responsible to meet this requirement through either their own resources, bilateral transactions or interchange through the pool AGC Clearing Market.

AGC Bid Price Submittal - Every unit capable of providing AGC service will have a bid price on file with the ISO to be expressed in $/MW/minute.

Regional AGC Requirement - The amount of AGC "required" for system operation will be determined as needed to maintain proper tie flow and frequency control. The Regional AGC Requirement will be equal to the total MW/minute of AGC ramping utilized by the ISO in the hour. If only one unit provided AGC during a one minute period and that unit was ramped up by 4 MW during that minute, the Regional AGC Requirement for the minute would be 4 MW/minute.

Physical Dispatch - In real time, the ISO will utilize AGC capable units to respond to system load, supply and transmission changes. It is intended that the dispatch software would provide the dispatcher with a list of AGC alternatives, their physical capability (sustainable

response rate), and the cost of the action. Cost of the action will consider the AGC bid price. The lost opportunity cost will be recovered in the 10 minute spinning reserve market.

Participant AGC Requirement - Since AGC is necessary for load following, regional AGC use within each hour will be allocated based on Participant loads. The Participant AGC Requirement will be equal to its allocation of the Regional AGC Requirement plus any bilateral sales.

Participant AGC Supply - The Participant AGC Supply will be equal to the quantity of AGC ramping utilized by the ISO from the Participant's resources in the hour plus any bilateral purchases of AGC.

AGC Clearing Price Determination (AGCCP) - The ISO will calculate an AGCCP for each hour. Within each hour, actual AGC blocks will be stacked by AGC cost from lowest to highest. AGC cost for these purposes will include the AGC bid price submittal expressed in $/MW/minute.

AGC Settlement - For each hour, the ISO would determine whether a Participant was a net seller or net buyer. If the hourly Participant AGC Supply was less than the hourly Participant AGC Requirement, the Participant would be responsible for paying for the AGC purchased at the hourly AGC Clearing Price (AGCCP). If the hourly Participant AGC Supply exceeded the hourly Participant AGC Requirement, the Participant would receive payment for the level of excess AGC supply at the hourly AGCCP.

III. E. Operating Reserves

III. E. 1 Overview

The following section details the changes proposed in the dispatch operations and settlement of Participant operating reserve requirements. The section provides a brief overview of the current practices, Participant obligations and proposed changes to economic dispatch and settlement of participant requirements. Through this presentation we intend to illustrate that unbundled operating reserve clearing markets can provide appropriate and equitable economic signals to encourage flexible unit characteristics.

III. E. 2 NEPOOL Today

In order to comply with NPCC and NERC reliability criteria, NEPOOL requires that a certain amount of operating reserve be reserved each hour to maintain sufficient reserves for use during the contingency loss of generating resources in the control area. NEPOOL implements this requirement through a requirement to hold a portion of this reserve in 10 minute spinning reserve. The current requirements are that a minimum 10 minute spinning reserve equal to 50% of the largest contingency, 10 minute non-spin reserve equal to 50% of the generation of the largest resource and 30 minute reserve equal to 50% of the second largest contingency be maintained. The quantity of 10 minute spinning reserve identified by dispatch may be higher than the level of the requirement to cover either 10 minute non-spinning reserve or 30 minute reserve requirements if that results in the lowest total cost dispatch. In like manner, the quantity of 10 minute non-spin reserve may be higher than the guideline criteria if displacement of 30 minute reserve results in a more economic overall dispatch.

Today's redispatch settlement system provides a bundled cost for energy and operating reserve requirements. Energy and operating reserve requirement input criteria determine along with unit costs the unit commitment. The redispatch production cost is a bundled cost,

representing the cost of unit commitments necessary to fulfill all energy and operating reserve requirements. The bundling of operating reserve costs are embedded in generation costs and energy interchange transactions within NEPOOL impedes NEPOOL's ability to comparably price ancillary services for non-Participants.

III. E. 3 Restructuring Proposal

Our restructuring proposal for operating reserves seeks to maintain the reliability and economy advantages of regional dispatch while modifying the unit pricing and settlement systems to accommodate the varied roles of existing and new Participants in the coming years. Under this system, each Participant will continue to be responsible to serve its full operating reserve responsibilities. Units will be submitted for central dispatch with separate energy, 10 minute spinning reserve, 10 minute non-spin reserve and 30 minute reserve bids. Participants could meet their operating reserve requirements through own generation (including unit entitlements), bilateral transactions or purchases through a NEPOOL Energy Clearing Market.

- **10 Minute Spinning Reserve**

Bid Price Submittal - Every unit capable of providing 10 minute spinning reserve (TMSR) service would have a bid price on file with the ISO. The bid price will be expressed in $/MW- hour. It would be at the unit owners option to submit revised bids each day. In the event no revision was made, the current price on file would continue to be effective.

Regional TMSR Requirement - The minimum amount of TMSR required would be equal to the current NEPOOL requirement of 50% of the generating level of the largest contingency. The Regional TMSR Requirement could be higher than this level to the extent economic system dispatch indicates TMSR displacement of 10 minute non-spin reserve and/or 30 minute

reserve provides the lowest total cost for the region. In most hours, the physical supply of TMSR in the region will exceed the TMSR requirement.

Participant TMSR Requirement - Each Participant bearing load responsibility will be allocated its share of the Regional TMSR Requirement for the hour based on their hourly load responsibility. The Participant TMSR Requirement will be equal to their load-based allocation of the Regional Requirement plus any bilateral sales of TMSR.

Participant TMSR Supply - The Participant TMSR Supply will be based on the quantity of TMSR selected by the ISO from the Participants resources in the actual dispatch plus any bilateral purchases of TMSR. The ISO selection of TMSR in the physical dispatch will be based on least cost dispatch across energy and the three operating reserve requirements and will be tracked and recorded by the ISO through dispatch software. All units selected by the ISO and backed down to provide AGC capability will be included in the Regional TMSR Requirement. The TMSR blocks selected will then be used to calculate the TMSR clearing price.

TMSR Clearing Price Determination (TMSRCP) - The ISO will calculate a TMSRCP for each hour. Within each hour, actual TMSR blocks will be stacked by TMSR cost from lowest to highest. TMSR cost for these purposes would include the TMSR bid price submittal expressed in $/MW-hour plus the lost opportunity cost of participation in the energy market. If the EBP was less than the ECP, then the lost opportunity cost would be equal to ECP - EBP. The highest cost block of (to be determined) MWH's within each hour would be used to determine the TMSR Clearing Price.

TMSR Settlement - For each hour, the ISO will determine whether a Participant was a net seller or net buyer. If the hourly Participant TMSR Supply was less than the hourly Participant

TMSR Requirement, the Participant would be responsible for paying for the TMSR purchased at the hourly TMSR Clearing Price (TMSRCP). If the hourly Participant TMSR Supply exceeded the hourly Participant TMSR Requirement, the Participant would receive payment for the level of excess TMSR at the hourly TMSRCP.

Lead unit owners would submit a 10 minute spinning reserve bid for each unit. The lead unit owner could influence its participation in this market through its bid price strategy and unit characteristics. Physical dispatch would consider serving the individual energy and operating reserve requirements in light of the product specific bids to deliver the lowest total cost dispatch. High costs within an individual product market would send signals to either increase the quantity of supply or modify bid price strategies.

The cost in $/MWh of individual blocks of 10 minute spinning reserve would be equal to their 10 minute spinning reserve bid in $/MWh, plus the lost opportunity cost (if any) equal to the difference between ECP and the unit energy bid. The 10 minute spinning reserve clearing price would be equal to the highest cost block of (to be determined) MWH of spinning reserve selected. Participant net interchange would be determined by subtracting the Participant requirement from the quantity of the Participant's 10 minute spinning reserve selected by the ISO. A positive net hourly interchange would reflect a net sale into the NEPOOL clearing market and a negative net interchange would reflect a net purchase from the NEPOOL clearing market. Net buyers and sellers would pay or receive compensation for their transactions at the 10 Minute Spinning Reserve Clearing Price.

10 Minute Non-Spinning Reserve

Bid Price Submittal - Every unit capable of providing 10 minute non-spin reserve (TMNS) service would have a bid price on file with the ISO. The bid price will be expressed in $/MW- hour.

Regional TMNS Requirement - The minimum amount of TMNS required will be equal to the current NEPOOL requirement of 50% of the generating level of the largest contingency. The Regional TMNS Requirement could be higher or lower than this level to the extent economic system dispatch indicates TMNS displacement of 30 minute reserve or displacement by TMSR is the least cost alternative.

Participant TMNS Requirement - Each Participant bearing load responsibility will be allocated its share of the regional TMNS requirement for the hour based on their hourly load responsibility. The Participant TMNS Requirement will be equal to their load-based allocation of the Regional TMNS Requirement plus any bilateral sales of TMNS.

Participant TMNS Supply - The Participant TMNS Supply will be equal to the quantity of TMNS selected by the ISO from the Participant's resources in the actual dispatch plus any bilateral purchases of TMNS. The ISO selection of TMNS in the physical dispatch will be based on least cost dispatch across energy and the three operating reserve requirements and will be tracked and recorded by the ISO through dispatch software. The TMNS blocks selected will then be used to calculate the TMNS clearing price.

TMNS Clearing Price Determination (TMNSCP) - The ISO will calculate a TMNSCP for each hour. Within each hour, actual TMNS blocks will be stacked by TMNS bid price from lowest to highest. The highest cost block of (to be determined) MWH's within each hour would be used to determine the TMNS Clearing Price.

TMNS Settlement - For each hour, the ISO would determine whether a Participant was a net seller or net buyer. If the hourly Participant TMNS Supply was less than the hourly Participant TMNS Requirement, the Participant would be responsible for paying for the TMNS purchased at the hourly TMNS Clearing Price (TMNSCP). If the hourly Participant TMNS Supply exceeded the hourly Participant TMNS Requirement, the Participant will receive payment for the level of excess TMNS at the hourly TMNSCP.

30 Minute Reserve

Bid Price Submittal - Every unit capable of providing 30 minute operating reserve (TMOR) service would have a bid price on file with the ISO to be expressed in $/MW- hour. It would be at the unit owners option to submit revised bids each day. In the event no revision was made, the current price on file would continue to be effective.

Regional TMOR Requirement - The minimum amount of TMOR required would be equal to the current NEPOOL requirement of 50% of the generating level of the second largest contingency. The actual Regional TMOR Requirement could be lower than this level to the extent economic system dispatch indicates displacement of TMOR by TMSR or TMNS is the least cost alternative.

Participant TMOR Requirement - Each Participant bearing load responsibility will be allocated its share of the regional TMOR requirement for the hour based on their hourly load responsibility. The Participant TMOR Requirement will be equal to their load-based allocation of the Regional TMOR Requirement plus any bilateral sales of TMOR.

Participant TMOR Supply - The Participant TMOR Supply will be equal to the quantity of TMOR selected by the ISO from the Participant's resources in the actual dispatch plus any

bilateral purchases of TMNS. The ISO selection of TMNS in the physical dispatch will be based on least cost dispatch across energy and the three operating reserve requirements and will be tracked and recorded by the ISO through dispatch software. The TMOR blocks selected will then be used to calculate the TMOR clearing price.

TMOR Clearing Price Determination (TMORCP) - The ISO will calculate a TMORCP for each hour. Within each hour, actual TMOR blocks will be stacked by TMOR bid price from lowest to highest. The highest cost block of (to be determined) MWH's within each hour would be used to determine the TMOR Clearing Price.

TMOR Settlement - For each hour, the ISO would determine whether a Participant was a net seller or net buyer. If the hourly Participant TMOR Supply was less than the hourly Participant TMOR Requirement, the Participant would be responsible for paying for the TMOR purchased at the hourly TMOR Clearing Price (TMORCP). If the hourly Participant TMOR Supply exceeded the hourly Participant TMOR Requirement, the Participant would receive payment for the level of excess TMOR at the hourly TMORCP.

III. F. Operable Capacity

III. F. 1. Overview

The following section details the creation of a new product market. The section provides a brief overview of the related current practices, new Participant obligations and settlement of Participant requirements. Through this presentation we intend to illustrate that an unbundled operable capacity clearing market could provide appropriate and equitable economic signals to encourage unit availability.

III. F. 2. NEPOOL Today

Today, NEPOOL encourages Participants to maintain the availability of their units through economic penalties in the energy and capacity settlement systems. Energy purchases from the pool not backed by sufficient available generation pay penalty-based energy rates for either scheduled outage service, unscheduled outage service or deficiency service. Capacity penalties for unavailability are included in the calculation of PIP and result in an increased allocation of the NEPOOL Objective Capability. Due to the 4 year nature of the PIP calculation, this signal tends to be a lagging indicator or signal.

III. F. 3. Restructuring Proposal

We propose an improved availability signal to replace these prior signals. A new requirement termed "Operable Capacity" would create a true market signal to encourage unit availability in real time.

Bid Price Submittal - Every unit entitlement would have an Operable Capacity bid price on file with the ISO prior to 2PM in order to be effective for the next day starting at midnight. The bid price would be expressed in $/MW- hour. It would be at the entitlement holders option to submit revised bids each day. In the event no revision was made, the current price on file would continue to be effective.

Participant Operable Capacity Requirement - Each Participant will be required to provide or purchase Operable Capacity equivalent to its hourly load, TMSR, TMNS and TMOR requirements plus any bilateral sales of Operable Capacity.

Participant Operable Capacity Supply - The Participant Operable Capacity Supply will be equal to the sum of its hourly available generation that was selected in the ISO stacking process plus any bilateral purchases of Operable Capacity.

Operable Capacity Clearing Price Determination (OCCP) - The ISO will calculate an OCCP for each hour. Within each hour, actual Operable Capacity blocks will be stacked by Operable Capacity bid price from lowest to highest. The highest cost block of (to be determined) MWH's within each hour would be used to determine the OCCP.

Operable Capacity Settlement - In each hour, Participants would the ISO would determine whether a Participant was a net seller or net buyer. If the hourly Participant Operable Capacity Supply was less than the hourly Participant Operable Capacity Requirement, the Participant would be responsible for paying for the Operable Capacity purchased at the hourly Operable Capacity Clearing Price (OCCP). If the hourly Participant Operable Capacity Supply exceeded the hourly Participant Operable Capacity Requirement, the Participant would receive payment for the level of excess Participant Operable Capacity Supply at the hourly OCCP.

IV. New England Regional Transmission Operations and Planning

IV. A. Overview

Our proposal addresses the following transmission issues: membership, governance, voting, dispute resolution (these issues are addressed in Section II of this document), pricing, planning and stranded cost recovery. (The most recent full draft of the regional transmission provisions is a work in progress. In their final form, we expect that these provisions will be integrated into the amended NEPOOL Agreement). The following is a summary of our transmission proposal on pricing, planning and stranded cost recovery.

IV. B . Transmission Pricing

IV. B. 1 Objective

The transmission pricing provisions will be designed to assure efficiency and equity, while being consistent with public policy and FERC regulation with appropriate transition mechanism to its final form.

IV. B. 2 Description

This proposal provides for regional services and local services. Regional services will consist of two elements, Regional Transaction Service ("RTS") and Regional Network Service ("RNS"). Local transmission service will include two elements, Local Network Service ("LNS") and Local Point-to-Point Service ("LPTP"). This structure includes incentives to minimize transmission cost and will provide for congestion pricing.

The LNS and LPTP will be subject to the terms, rates and conditions of individual transmission providers' tariffs filed with the FERC. Access to such tariffs will be provided under the NEPOOL Agreement. The load will not be credited for any generation in any allocation of costs in these tariffs.

The main elements of transmission pricing are described below.

- *Regional Transaction Service ("RTS")* must be purchased by an entity using transmission service for transmission of generation entitlements or system power to be used in meeting the NEPOOL Capability Responsibility or equivalent requirement, but only from points remote from its local network which use the facilities of other groups of regional transmission providers. This service will be optional for firming of energy and or ancillary services not counted in the Capability Responsibility. The RTS rate will be derived as a product of the fraction (f1) and total New England's annual PTF cost of service and divided by sum of the 12 monthly average peak load of all transmission

provider's local network customers. Each transmission provider shall recover revenues based on its allocated share of the transmission path relating to each transaction flowing across its system. Such allocation will be measured based on a source-sink method (the so-called "Yankee method"). The current discussions reflect RTS rate to start at $13/kW-yr. be phased down over a 5-year period to zero in year 6.

- *Regional Network Service ("RNS")* will consist of any transmission service other than service required to enable a Participant to meet NEPOOL Capability Responsibility or equivalent requirements and services for local network and non-NEPOOL transmission facilities. RNS will include non-firm services for transmission of ancillary services and energy services provided through NEPOOL and bilateral agreements. Payment for such services will be based on allocation of a fraction (f2) of PTF transmission cost of service to all load serving entities based on their load. (f1 + f2 = 100%.) The proposal is based on phasing up the RNS rate to recover the full PTF cost in year 6. These payments will be distributed to transmission providers based on allocation of revenue requirements and MW-miles (the so-called "UI method"), with varying percentages over 6 years as follows:

(RR%/MW-mile %)	75/25	80/20	85/15	90/10	95/5	100/0

- *Wheeling through and out:* Transmission rate for wheeling through and/or wheeling out of the region would be equal to RTS + RNS rate. Such revenues would be collected by the Pool and distributed to transmission providers based on the RTS distribution allocation. However, in case of off system sales to outside New England where generator is located on a system connected to a specific tie over which power is wheeled to outside,

such revenues would flow 100% to that transmission system provider for a period of 5 years to be credited in the LNS rate.

- *Congestion Pricing:* This issue will be under discussion and it is not yet clear whether transmission congestion is best dealt with through transmission provisions or through spot market. Under either method, there will be an incentive for the RTPC to increase transmission capability to relieve congestion.
- Support of new facilities is under discussion.
- Calculation and allocation of losses will be done by a method to be determined.
- *Grandfathering:* The following transactions will not pay for RTS and shall continue to be governed by the rates and other terms of the currently applicable transmission service arrangements: (1) transmission of original entitlements in existing Pool-Planned Units as described in the NEPOOL Agreement, as of the effective date of the amended NEPOOL Agreement; (2) other transmission of capacity and energy from Pool-Planned Units in effect on the effective date of the amended NEPOOL Agreement; (3) transmission of original entitlements pursuant to existing transmission agreements relating to Connecticut Yankee Atomic Power Company, Vermont Yankee Nuclear Corporation, Maine Yankee Atomic Power Company and Pilgrim 1 until such times when the RTS rate falls below the rates under these agreements listed in items (1) through (3) above respectively, at which points RTS rate would apply and the existing agreements would be terminated; (4) general use transmission rights that arise from agreements in effect on the effective date of the amended NEPOOL Agreement unless otherwise mutually agreed upon for early termination (as listed in that Agreement); and (5) transmission service under contracts

and other transactions listed in the amended NEPOOL Agreement under long term tariffs in effect on the effective date of the amended NEPOOL Agreement.

- *Tie Proposal:*

  a. Inclusion of MEPCO tie in NEPOOL transmission needs to be resolved.

  b. Allocation of NY and NB tie benefit pro rata load.

  c. Tie Benefit Wheeling

     2/3 of PTF full rate payment by all parties for wheeling of tie benefits for 5 years.

     - Who pays? All load servers receiving tie benefits.
     - Who receives? Owners of the PTF system connected to the New England side of the interface.

     NY tie revenue distribution: NU = 72%, NEP = 14%, VELCO = 14%

     NB tie revenue distribution: CMP = 78.32%, BH = 14.1%, MPS = 7.49%

     - Where do revenues go. Revenues will get credited in the LN rate of individual providers.

  d. All future transactions will be assigned an outside transaction adjustment (OTA). The OTA will be uniform for each interface. An exemption for existing transactions is under discussion.

- Hydro-Quebec tie benefits is a subject under discussion.
- Priority rights for use of ties is a subject under discussion.
- *Load Connected directly to PTF*: The proposal reflects a gradual reduction of LNS payments for the non-PTF wire facilities over 5 years from 100% to zero.

Transition Charge There will be a transition charge for a period of five years, at amounts to be determined.

IV. C Coordinated Regional Planning

IV. C. 1 Objective

The NEPOOL Regional Transmission Planning Committee will adopt a level of coordinated planning as defined by NERC. Planning will be coordinated under the direction of the NEPOOL Executive Committee.

IV. C. 2 Description

The RTPC will be the focal point for coordinated transmission planning to meet the regional needs of entities using the regional transmission network. The mission of the RTPC will be to actively and continuously promote the reliability, efficient use and necessary expansion of these facilities. The RTPC shall take such actions as necessary to provide for the effective coordination of providers' transmission planning activities and the coordination of planning activities with other regional entitles, including NEPOOL and a New England ISO, the New England states and all appropriate regulatory agencies. To carry out these responsibilities, the RTPC shall:

- develop and recommend to the Executive Committee reliability standards for the design and operation of the regional bulk power system in New England that, at a minimum, meet the requirements of the Northeast Power Coordinating Council (NPCC);
- monitor and assess conformance of the New England regional bulk power system to the accepted reliability criteria.

- develop a coordinated regional transmission plan which meets the overall goals of the interconnected system without relieving the individual transmission owners of the responsibility of planning for their individual system needs;
- coordinate the collection and exchange of necessary system data and future plans which are appropriate to conducting studies affecting the overall performance of the regional bulk power system;
- make recommendations to the Executive Committee for the establishment of goals, assumptions and methodologies to provide for the development of a coordinated regional transmission plan for New England;
- coordinate transmission planning activities with neighboring control areas and other groups of regional transmission providers;
- conduct regular assessments of the adequacy and economy of regional transmission services, including anticipated future needs;
- fulfill information reporting requirements to organizations having regulatory and reliability oversight;
- review and recommend action on proposed facility changes which may significantly affect the stability, reliability or operating characteristics of the New England regional bulk power system; and
- carry out other activities as directed by the Executive Committee.

IV. D. Stranded Costs Collected Through Regional Transmission Provisions

IV. D. 1 Objective

These provisions will be designed to ensure that the transmission provisions contained in the amended NEPOOL Agreement shall not be used to evade in whole or in part the stranded cost policies or charges established by the regulatory commission having appropriate jurisdiction.

IV. D. 2 Description

In the event that a retail end-use customer uses regional transmission services or facilities to purchase electricity from a new supplier, such customer will pay a stranded cost charge for access to those services or facilities equal to the amount of stranded cost that the customer would have paid under the policies or charges established by the regulatory commission with jurisdiction had the customer become an unbundled transmission services customer of its former supplier without using regional transmission service or facilities. The charge will be collected by NEPOOL or the owner of any facilities that are used to provide regional transmission service to the customer. The entity that collects the stranded cost charge will pay the proceeds to the customer's former supplier or the former supplier's affiliate or successor as directed by the former supplier.

Provided below are specific provisions dealing with stranded cost recovery.

- With respect to a retail end-use customer that becomes a domestic electric utility, electric company, public utility, municipal lighting plant or similar entity under state law or a wholesale customer taking service under a full or partial requirements contract, the amount of the stranded cost charge contained in the regional transmission provisions shall equal the amount of the stranded cost charge that the customer would have paid had it become an unbundled transmission services customer of its former supplier pursuant to

the then applicable policies or charges established by the Federal Energy Regulatory Commission (FERC).

- If NEPOOL should be expanded to include retail transmission services, then with respect to a retail end-use customer that becomes a retail end-use customer of a new supplier, the amount of the stranded cost collected through regional transmission provisions would equal the amount of the stranded cost charge that the customer would have paid if it had become an unbundled transmission services customer of its former supplier under the policies or charges established by the respective state commission or the FERC, whichever agency is ultimately determined to have jurisdiction over retail stranded costs.

Nothing in these provision is intended to affect or alter the rights or obligations of parties under wholesale requirements contracts. Nor will these provisions impair a utility's right to seek stranded cost relief from the appropriate regulatory body or judicial agency.

- *State authorized retail wheeling programs*: Administration of RTG tariffs for state authorized

retail wheeling programs will be in accordance with agreements reached for such programs. The regional transmission pricing provisions must allow for RNS and LNS payments from local distribution companies directly to customers as a wires access charge rather than to suppliers (whether the load is connected to transmission either directly or through a distribution system. Such provisions will facilitate retail choice as currently implemented in the New Hampshire pilot program and similar programs to be implemented in other New England states.

V. Conclusion

We believe that this proposal would work in the restructured electric industry, that it meets or exceeds the expectations of regulators, and that it fairly deals with all of the various interests represented in a restructured NEPOOL.